

Recommended Practice for Well Control Operations

API RECOMMENDED PRACTICE 59
SECOND EDITION, MAY 2006

REAFFIRMED, DECEMBER 2018



AMERICAN PETROLEUM INSTITUTE

Recommended Practice for Well Control Operations

Upstream Segment

API RECOMMENDED PRACTICE 59
SECOND EDITION, MAY 2006

REAFFIRMED, JANUARY 2012



AMERICAN PETROLEUM INSTITUTE

SPECIAL NOTES

API publications necessarily address problems of a general nature. With respect to particular circumstances, local, state, and federal laws and regulations should be reviewed.

Neither API nor any of API's employees, subcontractors, consultants, committees, or other assignees make any warranty or representation, either express or implied, with respect to the accuracy, completeness, or usefulness of the information contained herein, or assume any liability or responsibility for any use, or the results of such use, of any information or process disclosed in this publication. Neither API nor any of API's employees, subcontractors, consultants, or other assignees represent that use of this publication would not infringe upon privately owned rights.

API publications may be used by anyone desiring to do so. Every effort has been made by the Institute to assure the accuracy and reliability of the data contained in them; however, the Institute makes no representation, warranty, or guarantee in connection with this publication and hereby expressly disclaims any liability or responsibility for loss or damage resulting from its use or for the violation of any authorities having jurisdiction with which this publication may conflict.

API publications are published to facilitate the broad availability of proven, sound engineering and operating practices. These publications are not intended to obviate the need for applying sound engineering judgment regarding when and where these publications should be utilized. The formulation and publication of API publications is not intended in any way to inhibit anyone from using any other practices.

Any manufacturer marking equipment or materials in conformance with the marking requirements of an API standard is solely responsible for complying with all the applicable requirements of that standard. API does not represent, warrant, or guarantee that such products do in fact conform to the applicable API standard.

All rights reserved. No part of this work may be reproduced, stored in a retrieval system, or transmitted by any means, electronic, mechanical, photocopying, recording, or otherwise, without prior written permission from the publisher. Contact the Publisher, API Publishing Services, 1220 L Street, N.W., Washington, D.C. 20005.

Copyright © 2006 American Petroleum Institute

FOREWORD

This publication is under jurisdiction of the American Petroleum Institute, Upstream Department's Executive Committee on Drilling and Production Operations.

Drilling and well service unit (production well service, well workover, well completion, and plug and abandonment) operations are being conducted with full regard for personnel safety, public safety, and preservation of the environment in such diverse conditions as metropolitan sites, wilderness areas, ocean platforms, deepwater sites, barren deserts, wildlife refuges, and arctic ice packs. Recommendations presented in this publication are based on extensive and wide-ranging industry experience.

The goal of this voluntary recommended practice is to assist the oil and gas industry in promoting personnel and public safety, integrity of the drilling and well service equipment, and preservation of the environment for land and marine drilling and well service operations. This recommended practice is published to facilitate the broad availability of proven, sound engineering and operating practices. This publication does not present all of the operating practices that can be employed to successfully install and operate well control systems in drilling and well service operations. Nor does this publication imply that all of the practices herein are applicable to all drilling and well service operations. Drilling and well service operations throughout the world vary widely and take place under a wide range of downhole and surface conditions. Practices at one operation will not necessarily be required at a similar operation due to different conditions. Practices set forth herein are considered acceptable for accomplishing the job as described; equivalent alternative installations and practices may be utilized to accomplish the same objectives. Individuals and organizations using these recommended practices are cautioned that operations must comply with requirements of national, state, or local regulations. These requirements should be reviewed to determine whether violations may occur.

Users of recommendations set forth herein are reminded that constantly developing technology and specialized or limited operations do not permit complete coverage of all operations and alternatives. Recommendations presented herein are not intended to inhibit developing technology and equipment improvements or improved operational procedures. These recommended practices are not intended to obviate the need for qualified engineering and operations analyses and sound judgments as to when and where these recommended practices should be utilized to fit a specific drilling application.

This publication includes use of the verbs shall and should, whichever is deemed most applicable for the specific situation. For the purposes of this publication, the following definitions are applicable:

Shall—Indicates that the recommended practice(s) has universal applicability to that specific activity.

Should—Denotes a recommended practice(s) a) where a safe comparable alternative practice(s) is available; b) that may be impractical under certain circumstances; or c) that may be unnecessary under certain circumstances or applications.

Changes in the uses of these verbs are not to be effected without risk of changing the intent of recommendations set forth herein.

Nothing contained in any API publication is to be construed as granting any right, by implication or otherwise, for the manufacture, sale, or use of any method, apparatus, or product covered by letters patent. Neither should anything contained in the publication be construed as insuring anyone against liability for infringement of letters patent.

This document was produced under API standardization procedures that ensure appropriate notification and participation in the developmental process and is designated as an API stan-

dard. Questions concerning the interpretation of the content of this publication or comments and questions concerning the procedures under which this publication was developed should be directed in writing to the Director of Standards, American Petroleum Institute, 1220 L Street, N.W., Washington, D.C. 20005. Requests for permission to reproduce or translate all or any part of the material published herein should also be addressed to the director.

Generally, API standards are reviewed and revised, reaffirmed, or withdrawn at least every five years. A one-time extension of up to two years may be added to this review cycle. Status of the publication can be ascertained from the API Standards Department, telephone (202) 682-8000. A catalog of API publications and materials is published annually and updated quarterly by API, 1220 L Street, N.W., Washington, D.C. 20005.

Suggested revisions are invited and should be submitted to the Standards and Publications Department, API, 1220 L Street, NW, Washington, DC 20005, standards@api.org.

CONTENTS

	Page
1 SCOPE.....	1
1.1 Purpose.....	1
1.2 BOP Installations.....	1
1.3 Operations.....	1
1.4 Furthering the Understanding of Well Control.....	1
1.5 Deepwater.....	1
2 REFERENCES.....	1
2.1 Standards.....	1
2.2 Other References.....	2
3 GLOSSARY FOR WELL CONTROL OPERATIONS.....	2
3.1 Definitions.....	2
3.2 Acronyms and Abbreviations.....	6
4 PRINCIPLES OF WELL CONTROL.....	6
4.1 General.....	6
4.2 Conventions.....	6
4.3 Primary Well Control.....	7
4.4 The Flowing Well.....	7
4.5 Drilling or Workover Fluid.....	9
4.6 Influx Behavior.....	10
4.7 Formation Integrity Tests.....	10
4.8 Well Control Pressures.....	11
4.9 Well Close-in Procedures.....	14
4.10 Methods For Circulating Kicks At Constant Bottom-Hole Pressure.....	15
4.11 Non-Circulation Kill Methods.....	23
4.12 Comparison of Kill Methods.....	25
4.13 Choke Line Pressure—Subsea Stacks.....	26
4.14 Diverter Systems Applications.....	31
4.15 Well Control Worksheets.....	31
5 CAUSES OF KICKS.....	32
5.1 Conditions Necessary for a Kick.....	32
5.2 Insufficient Hydrostatic Pressure.....	32
5.3 Drilling Into an Adjacent Well.....	33
6 WELL CONTROL WARNING SIGNALS.....	33
6.1 General.....	33
6.2 Gain in Pit Volume.....	33
6.3 Increased Flow from Annulus.....	33
6.4 Volume of Drilling Fluid to Keep the Hole Full on a Trip is Less Than Calculated or Less Than Trip Book Record.....	33
6.5 Sudden Increase in Bit Penetration Rate.....	34
6.6 Change in Pump Speed or Pressure.....	34
6.7 Flow After Pumps Stopped.....	34
6.8 Gas-cut Drilling Fluid.....	34
6.9 Liquid-cut Drilling Fluid.....	35

CONTENTS

	Page
7 WELL PLANNING	35
7.1 Introduction	35
7.2 Data Availability and Gathering	35
7.3 Shallow Flows	36
7.4 Casing	37
7.5 Cementing	37
7.6 Blowout Prevention Equipment Selection	37
7.7 Drilling Fluid	38
7.8 Service Operations	38
7.9 Kick Response Plans	39
7.10 Riser Disconnect	39
7.11 Simultaneous Operations	39
7.12 Logistics	39
7.13 Safety and Medical	40
7.14 Communication	40
7.15 Training and Instruction	40
8 WELL CONTROL PROCEDURES FOR SURFACE DIVERTER INSTALLATIONS	41
8.1 Purpose	41
8.2 Installation of Equipment	41
8.3 Diverter Operation	41
8.4 Diverter Stripping Operations	42
9 CONTROL PROCEDURES—SURFACE BOPS	42
9.1 Pre-kick Planning	42
9.2 Well Control Procedures	43
9.3 Drill String Off-bottom	44
9.4 High-Angle and Horizontal Well Bores	45
9.5 Reference Notes For Section 9	45
10 WELL CONTROL PROCEDURES FOR SUBSEA BOPS	46
10.1 General	46
10.2 Additional Causes of Kicks Unique to Subsea Operations	46
10.3 Subsea Exceptions to Control Procedures	46
10.4 Special Subsea Procedures	47
11 WELL CONTROL PROCEDURES—RECOMMENDED RIG PRACTICES	48
11.1 Well Control System Equipment Installation	48
11.2 Well Control Equipment Installation Test	49
11.3 Crew Drills	49
11.4 Trip Tanks	50
11.5 Gas-Cut Drilling Fluid	50
11.6 Trip Book	50
11.7 Pre-Kick Information	52
11.8 Minimize Time Out of the Hole	52
11.9 Trip Margin	52
11.10 Short Trip	52
11.11 Rig Practices for Handling Pressure	54

CONTENTS

	Page
11.12 Rig Practices for Pipe Handling	54
11.13 Drill Stem Tests.	54
12 PROCEDURES FOR DEALING WITH SPECIAL PROBLEMS	54
12.1 Introduction.	54
12.2 Pump Failure in a Kick Situation	55
12.3 Excessive Casing Pressure	55
12.4 Pipe Problems with a Well Kick.	56
12.5 Procedures for Gas Bubble Migration	59
12.6 Gas Influx In Cemented Annulus.	59
12.7 Drill Stem Testing.	60
12.8 Stripping Procedures.	60
12.9 Bullheading and Top Kill Methods	61
13 SLURRIES AND PLUGS TO DEAL WITH LOST CIRCULATION AND UNDERGROUND BLOWOUTS	61
13.1 Introduction.	61
13.2 Lost Circulation	61
13.3 Underground Blowouts	61
13.4 Barite Plugs.	62
13.5 Squeeze Slurries	64
APPENDIX A KICK PRESSURE AND GRADIENT CALCULATIONS	67
APPENDIX B WELL CONTROL WORKSHEETS.	77
 Figures	
4.1 Example of Primary Well Control Conditions	7
4.2 Well Performance	8
4.3 Equipment Performance Relationship	8
4.4 Equipment & Well Performance Curves	8
4.5 Dynamic Kill	8
4.6 Static Well Kick Pressures	12
4.7 Equivalent Circulating Density	13
4.8 Well Closed-In on a Kick	14
4.9 Closed-In Drill Pipe Pressure	14
4.10 Gas Influx Migrating Up The Hole.	15
4.11 Stabilized Pumping of A Kick	17
4.12 Casing Pressure And Gas Volume Resulting From Using The Driller's Method .	19
4.13 Casing Pressure and Gas Volume Using the Driller's Method	20
4.14 Drill Pipe Pressure Schedule for the Wait and Weight Method	21
4.15 Typical Casing Pressure Resulting from Using Wait and Weight Method	22
4.16 Drill Pipe Pressure Schedule-Concurrent Method	24
4.17 Typical Casing Pressure Resulting From Using Concurrent Method	25
4.18 Example Of Approximate Casing Pressures With Different Kill Methods.	27
4.19 Pressure Loss versus Flow Rate	28
4.20 Pressure Loss through Choke Line and Manifold With Choke Full Open	29
11.1 Loss of Effective Drilling Fluid Density Due to Gas Cut	51
A.1 Weight of a Gas Kick, 0.6 Gravity Gas	69
A.2 Maximum Surface Pressure of A Zero Intensity Gas Kick	70

CONTENTS

	Page
A.3 Factor for Determining the Maximum Surface or Casing Shoe Pressure while Killing a Gas Kick with a Constant Bottom-Hole Pressure Method	71
Tables	
11.1 Example Form from a Trip Book	53
12.1 Indicators of Possible Problems while Circulating Out a Kick	57
13.1 Barite Slurry Formulations	62
13.2 Slurry Volumes	63
13.3 Barite Required (API Barite Specific Gravity = 4.20)	63
13.4 Diesel Oil-Bentonite Drilling Fluid Reactive Slurries	63
13.5 Trial Mixing Ratios for Reactive Slurry Mixtures	65
13.6 Materials Quantities for Mixing One Barrel of HWL-HS Cement Slurry	66

Recommended Practice for Well Control Operations

1 Scope

1.1 PURPOSE

The purpose of these recommended practices is to provide information that can serve as a voluntary industry guide for safe well control operations. This publication is designed to serve as a direct field aid in well control and as a technical source for teaching well control principles. This publication establishes recommended operations to retain pressure control of the well under pre-kick conditions and recommended practices to be utilized during a kick. It serves as a companion to API RP 53, *Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells* and API RP 64 *Recommended Practice for Diverter Systems Equipment and Operations* (reader should check for the latest edition). RP 53 establishes recommended practices for the installation and testing of equipment for the anticipated well conditions and service and RP 64 establishes recommended practices for installation, testing, and operation of diverters systems and discusses the special circumstances of uncontrolled flow from shallow gas formations.

1.2 BOP INSTALLATIONS

The recommended practices are separated into two main systems:

1. Blowout preventers (BOPs) at the surface within reach and sight of the driller or well service unit operator, and
2. BOPs installed on the seafloor with relatively long choke and kill lines.

In this publication, sections have been prepared to establish practices and procedures pertaining to both surface BOP installations and subsea BOP installations. The delineation between surface BOP installations and subsea BOP installations is mainly on an exception basis, and the recommendations made for surface installations apply to subsea installations unless exceptions are stated. The recommended practices can apply to drilling, well service unit, and coiled tubing unit operations. The fundamentals of well flow and well control are the same.

1.3 OPERATIONS

This publication was developed to enhance well control by proper planning and execution and thus avoid a kick. The publication also deals with the eventuality that a well kick may occur and presents details for handling such a kick using basic control methods. Details of these basic control methods are presented for both surface and subsea BOP stack installations. Suggested considerations and modifications to the basic control methods, which may be dictated by special problems or well conditions, are also covered. Recommended

well control worksheets for surface and subsea BOP installations are included in Appendix B. Instructions are included for completing and use of the well control worksheets. Recommended practices set forth in this publication are considered adequate to meet specified well conditions. It is recognized that there are alternate procedures that can be utilized in well control that may be equally as effective in meeting the well requirements and promoting safety and efficiency.

1.4 FURTHERING THE UNDERSTANDING OF WELL CONTROL

Details of well control technology and reasons for the recommended procedures are included in Section 4, "Principles of Well Control." Section 4 was prepared so it can be used as a technical base for instructing personnel in well control operations. Appendix A contains several special pressure and pressure gradient calculations and examples to further emphasize the techniques and calculations that can aid a well control supervisor in understanding well control operations.

1.5 DEEPWATER

The International Association of Drilling Contractors (IADC) has published guidelines for planning and drilling deepwater wells, IADC Deepwater Well Control Guidelines, 1998 Edition. The reader is referred to that document for more complete coverage of deepwater well control.

2 References

2.1 STANDARDS

The following standards contain provisions, which through reference in this text, constitute provisions of this standard. All standards are subject to revision and users are encouraged to investigate the possibility of applying the most recent editions of the standards indicated below:

API

Spec 6A	<i>Wellhead and Christmas Tree Equipment</i>
RP 5C1	<i>Recommended Practice for Care and Use of Casing and Tubing</i>
RP 5C7	<i>Recommended Practice for Coiled Tubing Operations in Oil and Gas Well Services</i>
RP 7G	<i>Drill Stem Design and Operating Limits</i>
RP 10B	<i>Recommended Practice for Testing Well Cements</i>
RP 13D	<i>Rheology and Hydraulics of Oil-Well Drilling Fluids</i>
RP 13B-1	<i>Standard Procedure for Field Testing Water-based Drilling Fluids</i>

RP 13B-2	<i>Standard Procedure for Field Testing Oil-based Drilling Fluids</i>
Spec 16A	<i>Specification for Drill Through Equipment</i>
RP 16Q	<i>Design, Selection, Operation and Maintenance of Marine Drilling Riser Systems</i>
RP 49	<i>Recommended Practice for Drilling and Well Servicing Operations Involving Hydrogen Sulfide</i>
RP 53	<i>Blowout Prevention Equipment Systems for Drilling Wells</i>
RP 64	<i>Recommended Practice for Diverter Systems Equipment and Operations</i>
RP 505	<i>Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities</i>
ASTM ¹	
D-1418	<i>Practice for Rubber and Rubber Lattices - Nomenclature</i>
NACE ²	
MR 01-75	<i>Materials for use in H₂S-containing Environments in Oil and Gas Production</i>

2.2 OTHER REFERENCES

IADC³

IADC Deepwater Well Control Guidelines

3 Glossary for Well Control Operations

3.1 DEFINITIONS

3.1.1 abnormal pressure: Pore pressure in excess of that pressure resulting from the hydrostatic pressure exerted by a vertical column of water with salinity normal for the geographic area.

3.1.2 accumulator: A pressure vessel charged with nitrogen or other inert gas and used to store hydraulic fluid under pressure for operation of BOPs.

3.1.3 annular preventer: A device, which can seal around any object in the well bore or upon itself. Compression of a reinforced elastomer packing element by hydraulic pressure effects the seal.

3.1.4 annulus: The space between the drill string and the inside diameter of the hole being drilled, the last string of casing set in the well, or the marine riser.

3.1.5 annulus friction pressure: Circulating pressure loss inherent in the annulus between the drill string and casing or open hole.

3.1.6 backpressure (casing pressure, choke pressure): The pressure existing at the surface on the casing side of the drill string/annulus flow system.

3.1.7 barite plug: A settled volume of barite particles from a barite slurry placed in the well bore to seal off a pressured zone.

3.1.8 barite slurry: A mixture of barium sulfate, chemicals, and water of a unit density between 18 and 22 pounds per gallon (lb/gal).

3.1.9 belching: A slang term to denote flowing by heads.

3.1.10 bell nipple: A piece of pipe, with inside diameter equal to or greater than the BOP bore, connected to the top of the BOP or marine riser with a side outlet to direct the drilling fluid returns to the shale shaker or pit. Usually has a second side outlet for the fill-up line connection.

3.1.11 bleeding: Controlled release of fluids from a closed and pressured system in order to reduce the pressure.

3.1.12 blind rams (blank, master): Rams whose ends are not intended to seal against any drill pipe or casing. They seal against each other to effectively close the hole.

3.1.13 blind/shear rams: Blind rams with a built-in cutting edge that will shear tubulars that may be in the hole, thus allowing the blind rams to seal the hole. Used primarily in subsea systems.

3.1.14 blowout: An uncontrolled flow of well fluids and/or formation fluids from the well bore.

3.1.15 blowout preventer (BOP): A device attached to the casinghead that allows the well to be sealed to confine the well fluids to the well bore.

3.1.16 blowout preventer drill: A training procedure to determine that rig crews are completely familiar with correct operating practices to be followed in the use of blowout prevention equipment. A “dry run” of blowout preventive action.

3.1.17 blowout preventer operating and control system (closing unit): The assembly of pumps, valves, lines, accumulators, and other items necessary to open and close the blowout preventer equipment.

3.1.18 blowout preventer stack: The assembly of well control equipment including preventers, spools, valves and nipples connected to the top of the wellhead.

3.1.19 BOPE: An abbreviation for blowout preventer equipment.

3.1.20 BOP: An abbreviation for blowout preventer.

¹ASTM International, 100 Barr Harbor Drive, P.O. Box C700, West Conshohocken, PA, 19428-2959, www.astm.org

²NACE International, 1440 South Creek Drive, Houston, Texas 77084-4906, www.nace.org

³International Association of Drilling Contractors, P.O. Box 4287, Houston, TX 77210-4287, www.iadc.org

3.1.21 borehole pressure: Total pressure exerted in the well bore by a column of fluid and/or backpressure imposed at the surface.

3.1.22 bottom-hole pressure: Depending upon the context, either a pressure exerted by a column of fluid contained in the well bore or the formation pressure at the depth of interest.

3.1.23 broaching: Venting of fluids to the surface or to the seabed through channels external to the casing.

3.1.24 bullheading: A term to denote pumping into closed-in well without returns.

3.1.25 casing pressure: See Backpressure.

3.1.26 casing seat test: A procedure whereby the formation immediately below the casing shoe is subjected to a pressure equal to the pressure expected to be exerted later by a higher drilling fluid density or by the sum of a higher drilling fluid density and backpressure created by a kick.

3.1.27 casing shoe: A tool joint connected to the bottom of a string of casing designed to guide the casing past irregularities in the open hole; usually rounded at the bottom in shape and composed of drillable materials.

3.1.28 choke: A device with either a fixed or variable aperture used to control the rate of flow of liquid and/or gas.

3.1.29 choke manifold (control manifold): The system of valves, chokes, and piping to control flows from the annulus and regulate pressures in the drill string/annulus flow system.

3.1.30 choke line: The high-pressure piping between BOP outlets or wellhead outlets and the choke manifold.

3.1.31 choke pressure: See Backpressure.

3.1.32 circulating head: A device attached to the top of drill pipe or tubing to allow pumping into the well.

3.1.33 closing unit: The assembly of pumps, valves, lines, accumulators, and other items necessary to open and close the BOP equipment.

3.1.34 conductor casing or conductor pipe (onshore and bottom-supported offshore installations): A relatively short string of large diameter pipe that is set to keep the top of the hole open and provide a means of returning the upward flowing drilling fluid from the well bore to the surface drilling fluid system until the first casing string is set in the well.

3.1.35 control panel, remote: A panel containing a series of controls that will operate the valves on the control manifold from a remote point.

3.1.36 cut drilling fluid: Well control fluid, which has been reduced in density or unit weight because of entrainment of less dense formation fluids or air.

3.1.37 degasser: A vessel, which utilizes pressure reduction and/or inertia to separate entrained gases from the liquid phases.

3.1.38 displacement: The volume of steel in the tubulars and devices inserted and/or withdrawn from the well bore.

3.1.39 diverter: A device attached to the wellhead or marine riser to close the vertical access and direct flow into a line away from the rig.

3.1.40 diverter system: The assemblage of an annular sealing device, flow control means, vent system components, and control system which facilitates closure of the upward flow path of the well fluid and opening of the vent to the atmosphere.

3.1.41 drill pipe safety valve: An essentially full-opening valve located on the rig floor with threads to match the drill pipe in use. This valve is used to close off the drill pipe to prevent flow.

3.1.42 Drill Stem Test (DST): A test conducted to determine production flow rate and/or formation pressure prior to completing the well.

3.1.43 drill string float: A check valve in the drill string that will allow fluid to be pumped into the well but will prevent flow from the well through the drill pipe.

3.1.44 drilling break: A change in the rate of penetration that may or may not be a result of penetrating a pressured reservoir.

3.1.45 drilling spool: A flanged joint placed between the BOP and casing-head or between BOPs that serve as a spacer or crossover.

3.1.46 drive pipe: A relatively short string of large diameter pipe usually set in a drilled hole in onshore operations; it is normally washed, driven, or forced into the ground in bottom-supported offshore operations; sometimes referred to as structural pipe.

3.1.47 dynamic well kill procedure: A planned operation to control a flowing well by injecting fluid of a sufficient density and at a sufficient rate into the well bore to effect a kill without completely closing in the well with the surface containment equipment.

3.1.48 Equivalent Circulating Density (ECD): The sum of pressure exerted by hydrostatic head of fluid, drilled solids, and friction pressure losses in the annulus divided by depth of interest and by 0.052, if ECD is to be expressed in pounds per gallon (lb/gal).



3.1.49 final circulating pressure: Drill string pressure required to circulate at the selected kill-rate adjusted for increase in kill drilling fluid density over the original drilling fluid density; used from the time kill drilling fluid reaches the bottom of the drill string until kill operations are completed or a change in either kill drilling fluid density or kill-rate is effected.

3.1.50 fluid density: The unit weight of fluid; e.g., pounds per gallon (lb/gal).

3.1.51 formation breakdown: An event occurring when borehole pressure is of magnitude that the exposed formation accepts whole fluid from the borehole.

3.1.52 formation competency (formation integrity): The ability of the formation to withstand applied pressure.

3.1.53 formation competency test (formation integrity test): Application of pressure by superimposing a surface pressure on a fluid column in order to determine ability of a subsurface zone to withstand a certain hydrostatic pressure.

3.1.54 formation fracture gradient: The hydrostatic value expressed in psi/ft. that is required to initiate a fracture in a subsurface formation (geologic strata).

3.1.55 formation integrity: See Formation Competency.

3.1.56 formation integrity test: See Formation Competency Test.

3.1.57 formation pressure (pore pressure): Pressure exerted by fluids within the pores of the formation (see Pore Pressure).

3.1.58 flow line sensor: A device to monitor rate of fluid flow from the annulus.

3.1.59 fracture gradient (frac gradient): The pressure gradient (psi/ft) at which the formation accepts whole fluid from the well bore.

3.1.60 gas buster: A slang term to denote a mud: gas separator.

3.1.61 gas cut drilling fluid: Drilling Fluid that has become entrained with gas from previously drilled gas bearing formation which in turn lowers the drilling fluid density and hydrostatic head of the drilling fluid column.

3.1.62 gunk plug: A volume of gunk slurry placed in the well bore.

3.1.63 gunk slurry: A slang term to denote a mixture of diesel oil and bentonite.

3.1.64 gunk squeeze: Procedure whereby a gunk slurry is pumped into a subsurface zone.

3.1.65 H₂S: An abbreviation for hydrogen sulfide.

3.1.66 hydrogen sulfide: A highly toxic, flammable, corrosive, gas sometimes encountered in hydrocarbon bearing formations.

3.1.67 hydrogen sulfide service: Refers to equipment designed to resist corrosion and hydrogen embrittlement caused by exposure to hydrogen sulfide.

3.1.68 hard close-in: To Close-in a well by closing a BOP with the choke and/or choke line valve closed.

3.1.69 hydrostatic head: The true vertical length of fluid column, normally in feet.

3.1.70 hydrostatic pressure (hydrostatic head): The pressure that exists at any point in the well bore due to the weight of the vertical column of fluid above that point.

3.1.71 influx: The flow of fluids from the formation into the well bore.

3.1.72 initial circulating pressure: Drill pipe pressure required to circulate initially at the selected kill-rate while holding casing pressure at the closed-in value; numerically equal to kill-rate circulating pressure plus closed-in drill pipe pressure.

3.1.73 Inflow Performance (IPR): represents the ability of a well to produce fluids and is typically represented by the curve of a plot of flowing pressure versus flow rate.

3.1.74 inside BOP: A device that can be installed in the drill string that acts as a check valve allowing drilling fluid to be circulated down the string but prevents back flow.

3.1.75 kelly: The uppermost component of the drill string; the kelly is an extra-heavy joint of pipe with flat or fluted sides that is free to move vertically through a "kelly bushing" in the rotary table; the kelly bushing imparts torque to the kelly and thereby the drill string is rotated.

3.1.76 kelly cock: A valve immediately above the kelly that can be closed to confine pressures inside the drill string.

3.1.77 kelly valve, lower: An essentially full-opening valve installed immediately below the kelly, with outside diameter equal to the tool joint outside diameter.

3.1.78 kick: Intrusion of formation fluids into the well bore.

3.1.79 kill drilling fluid density: The unit weight, e.g., pounds per gallon (lb/gal), selected for the fluid to be used to contain a kicking formation.

3.1.80 kill line: The high-pressure piping between the pumps and BOP outlets or wellhead outlets.

3.1.81 kill-rate: A predetermined fluid circulating rate, expressed in fluid volume per unit time, which is to be used to

circulate under kick conditions. The kill-rate is usually some selected fraction of the circulating rate used while drilling.

3.1.82 kill-rate circulating pressure: Pump pressure required to circulate kill-rate volume under non-kick conditions.

3.1.83 leak-off test: Application of pressure by superimposing a surface pressure on a fluid column in order to determine the pressure at which the exposed formation accepts whole fluid.

3.1.84 lost circulation (lost returns): The loss of whole drilling fluid to the well bore.

3.1.85 lost returns: See Lost Circulation.

3.1.86 low choke pressure procedure: Consists of circulating and weighting up the drilling fluid, both at the maximum rates, while holding the maximum allowable casing pressure on the choke.

3.1.87 lubrication: Alternately pumping a relatively small volume of fluid into a closed well bore system and waiting for the fluid to fall toward the bottom of the well.

3.1.88 marine riser system: The extension of the well bore from the subsea BOP stack to the floating drilling vessel which provides for fluid returns to the drilling vessel, supports the choke, kill, and control lines, guides tools into the well, and serves as a running string for the BOP stack.

3.1.89 mud-gas separator: A vessel for removing free gas from the drilling fluid returns.

3.1.90 normal pressure: Formation pressure equal to the pressure exerted by a vertical column of water with salinity normal for the geographic area.

3.1.91 overbalance: The amount by which pressure exerted by the hydrostatic head of fluid in the well bore exceeds formation pressure.

3.1.92 pack-off or stripper: A device with an elastomer packing element that depends on pressure below the packing to effect a seal in the annulus. Used primarily to run or pull pipe under low or moderate pressures. This device is not dependable for service under high differential pressures.

3.1.93 pipe rams: Rams whose ends are contoured to seal around pipe to close the annular space. Separate rams are necessary for each size (outside diameter) pipe in use.

3.1.94 pore pressure (formation pressure): Pressure exerted by the fluids within the pore space of a formation.

3.1.95 pressure gradient, normal: The normal pressure divided by true vertical depth.

3.1.96 primary well control: Prevention of formation fluid flow by maintaining a hydrostatic pressure equal to or greater than formation pressure.

3.1.97 Productivity Index (PI): The PI represents one point on an inflow performance curve (IPR) and is defined as the well flow in barrels per day per psi pressure drop.

3.1.98 Remotely Operated Vehicle (ROV): An unmanned vehicle for offshore subsea use.

3.1.99 replacement: The process whereby a volume of fluid equal to the volume of steel in tubulars and tools withdrawn from the well bore is returned to the well bore.

3.1.100 rotating head or rotating drilling head: A rotating, low pressure sealing device used in drilling operations utilizing air, gas, or foam (or any other drilling fluid whose hydrostatic pressure is less than the formation pressure) to seal around the drill stem above the top of the BOP stack.

3.1.101 rotating stripper head: A sealing device installed above the BOPs and used to close the annular space about the drill pipe or kelly when pulling or running pipe under pressure.

3.1.102 rotary table: A device through which passes the bit and drill string and that transmits rotational action to the kelly.

3.1.103 safety factor: In the context of this publication, an incremental increase in drilling fluid density beyond the drilling fluid density indicated by calculations to be needed to contain a kicking formation.

3.1.104 saltwater flow: An influx of formation saltwater into the well bore.

3.1.105 shale shaker: A vibrating screen that removes relatively large size cuttings from the drilling fluid returns.

3.1.106 shear rams: BOP rams with a built-in cutting edge that will shear tubulars that may be in the hole.

3.1.107 soft close-in: To Close-in a well by closing a BOP with the choke and choke line valve open, then closing the choke while monitoring the casing pressure gauge for maximum allowable casing pressure.

3.1.108 sour gas: Natural gas containing hydrogen sulfide.

3.1.109 space-out: Procedure conducted to position a predetermined length of drill pipe above the rotary table so that a tool joint is located above the subsea preventer rams on which drill pipe is to be suspended (hung-off) and so that no tool joint is opposite a set of preventer rams after drill pipe is hung-off.

3.1.110 space-out joint: The joint of drill pipe used in hang off operations so that no tool joint is opposite a set of preventer rams.

3.1.111 squeezing: Pumping fluid into one side of the drill pipe/annulus flow system with the other side closed to allow no outflow.

3.1.112 stripping: A procedure for running or pulling pipe from the well bore with pressure in the annulus.

3.1.113 structural casing: The outer string of large-diameter, heavy-wall pipe installed in wells drilled from floating installations to resist the bending moments imposed by the marine riser and to help support the wellhead installed on the conductor casing.

3.1.114 surging: A rapid increase in pressure downhole that occurs when drill stem is lowered too fast or when the mud pump is brought up to speed after starting.

3.1.115 swabbing: The lowering of the hydrostatic pressure in the well bore due to upward movement of tubulars and/or tools.

3.1.116 target: A bull plug or blind flange at the end of a tee to prevent erosion at a point where change in flow direction occurs.

3.1.117 targeted: Refers to a fluid piping system in which flow impinges upon a lead-filled end (target) or a piping tee when fluid transits a change in direction.

3.1.118 trip gas: An accumulation of gas, which enters the hole while a trip is made.

3.1.119 trip margin: An incremental increase in drilling fluid density to provide an increment of overbalance in order to compensate for effects of swabbing.

3.1.120 tubulars: Drill pipe, drill collars, tubing, and casing.

3.1.121 underbalance: The amount by which formation pressure exceeds pressure exerted by the hydrostatic head of fluid in the well bore.

3.1.122 underground blowout: An uncontrolled flow of formation fluids from a subsurface zone into a second subsurface zone.

3.1.123 weight cut: The amount by which drilling fluid density is reduced by entrained formation fluids or air.

3.1.124 wireline preventers: Preventers installed on top of the well or drill string as a precautionary measure while running wirelines. The preventer packing will close around the wireline.

3.2 ACRONYMS AND ABBREVIATIONS

The following acronyms and abbreviations are used in this publication:

API	American Petroleum Institute
BOP	Blowout Preventer
IADC	International Association of Drilling Contractors
ID	Inside Diameter
OD	Outside Diameter
psi	pounds per square inch

4 Principles of Well Control

4.1 GENERAL

Formation flow during drilling and well servicing operations is generally referred to as a “kick.” Formation fluid that flows into the well bore is referred to as “well influx.” If not controlled, a kick may result in a blowout. Well control procedures are intended to safely prevent or handle kicks and re-establish primary well control. This Section discusses common elements and principles of well control. Appendix A, Kick Pressure and Gradient Calculations, contains additional discussion and calculations for well pressure gradients and well control. Well control procedures and practices are discussed in other Sections. However, each is based on the basic principles referred to in this Section.

4.2 CONVENTIONS

Most of this document and the examples are written from a drilling operations perspective. The principles and procedures in this document cover other operations where well control principles and practices are used such as completion, workover, well service, and plug and abandonment.

4.2.1 Design for Specific Rig, Equipment, and Conditions

The drilling, completion, workover, well service, and plug and abandonment operations are done with a wide range of rigs, equipment, and in a variety of conditions. The procedures contained herein are of a general nature and must be reviewed and modified for the specific rig, equipment, and conditions expected in a particular operation.

4.2.2 Drill Pipe/Tubing/Casing

Unless otherwise noted, the term “drill pipe” can also apply to any string of pipe being run in the hole whether it be drill pipe, drill collars, tubing, casing, a liner, or coiled tubing.

4.2.3 Drilling/Workover Fluid

Unless otherwise noted, the term “drilling fluid” can also apply to “workover” or “completion” fluid. Drilling and workover fluids can be gas, liquid, or foam (refer to 4.5).

4.2.4 Circulation

Unless otherwise noted, the term “circulation” refers to conventional circulation, which is circulating fluids down the interior of a string of pipe in the well and up the annulus. Reverse circulation is the opposite; fluid is circulated down the annulus and up the pipe in the hole.

4.3 PRIMARY WELL CONTROL

Primary well control is the maintenance of hydrostatic pressure in the well bore that is equal to or greater than the formation pressure prevents formation flow. Figure 4.1 illustrates an example. The drilling fluid column pressure is 5,200 psi at the bottom of a 10,000 ft. column of 10.0 lb/gal drilling fluid; the formation fluid pressure is 4,650 psi. The difference, or overbalance pressure, is 550 psi; therefore the formation in the well will not flow.

4.4 THE FLOWING WELL

Understanding well control requires some background understanding of well flow. A drilling well experiencing a flow from a formation is acting as a producing well. A producing well is a system of interrelated components. The behavior or performance of any one of the components is related to the performance of each of the other components. These relationships determine the rate and volume at which a

particular formation in a well will flow. Two relationships require examination: well performance and equipment performance.

4.4.1 Well Performance

Flow rate versus pressure is calculated through the flow path from the bottom of the well to the top. Well performance is independent of the equipment downstream of the point of analysis. The inflow performance relationship (IPR) is the most common well performance relationship. IPR is the flow rate (q) versus pressure at the formation face (refer to Figure 4.2). The more common term, productivity index (PI), is a special case of IPR that applies only to single phase, incompressible flow.

The type of reservoir and reservoir characteristics influence the production rate. Reservoirs can be one of three basic drive mechanisms: water drive, solution gas drive, or gas cap expansion drive, or combinations of the three. Flow may be water, gas, oil or combinations of all three. The productivity of a well increases as formation permeability and net pay increase; as productivity increases, so does kick intensity. A high-angle or horizontal well bore through a section of formation will have more feet of net pay than a vertical well bore. If permeability is the same in both wells, the one with the most pay has potential for a larger kick. These factors influ-

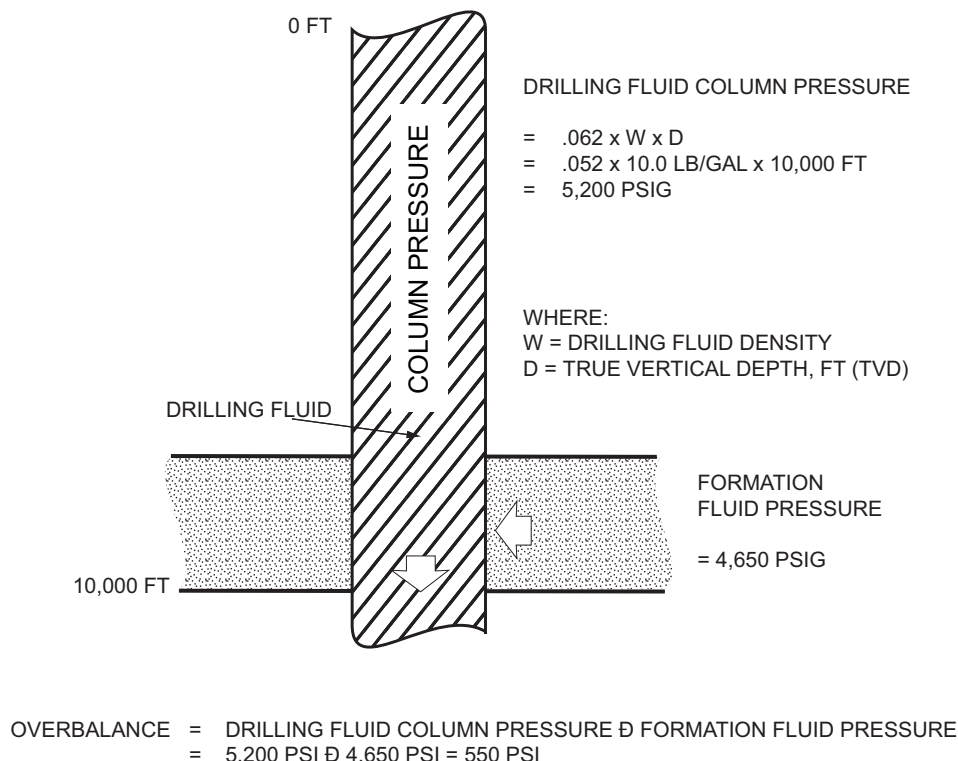


Figure 4.1—Example of Primary Well Control Conditions

ence the shape of the IPR curves for particular wells. The same is true for the equipment performance curve. The size of the hole, the size of casings, and the size of the tubular goods influence the shape of a particular equipment performance curve.

4.4.2 Equipment Performance

Flow rate versus pressure is calculated at the point of analysis (refer to Figure 4.3).

Every point on the equipment performance curve is valid. However, the only valid value for the well system is at the intersection of the IPR and equipment performance curve (refer to Figure 4.4).

4.4.3 Conditions for Well Flow

If the equipment performance curve for gas/liquid flows in the well bore does not cross the well performance curve (stays to the right of it in the convention shown in example Figure 4.5), the well will not flow. To kill a well, the equipment performance curve must be designed to exceed the well performance curve. This is called “dynamic kill.” This means the backpressure that can be applied by the hydrostatic head plus the hydraulic friction of the fluids in the annulus must exceed the inflow performance relationship (IPR).

4.4.4 Application of Backpressure to Control Well Flow

Backpressure can be affected by the pump rate, drilling fluid density, and flow restriction in the equipment downstream of the formation face. All of these effects should be considered but the choke is used to adjust backpressure during kill operations. Following are three examples:

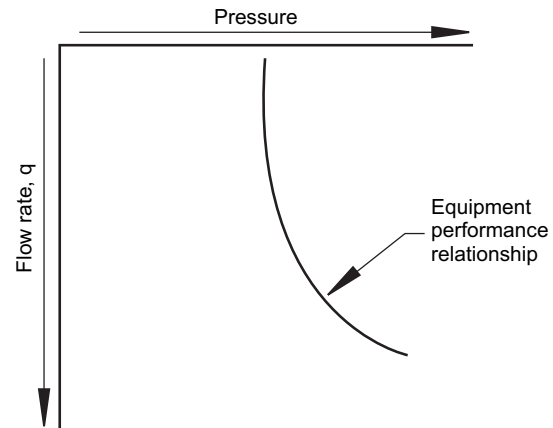


Figure 4.3—Equipment Performance Relationship

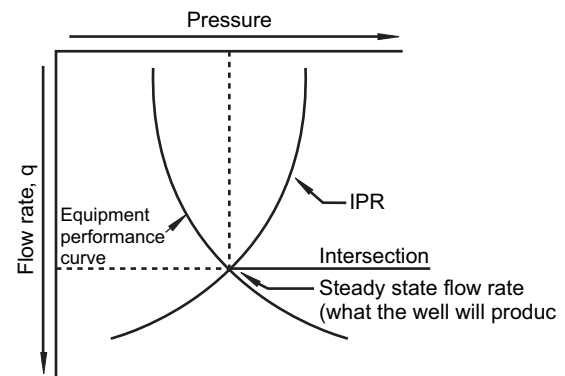


Figure 4.4—Equipment & Well Performance Curves

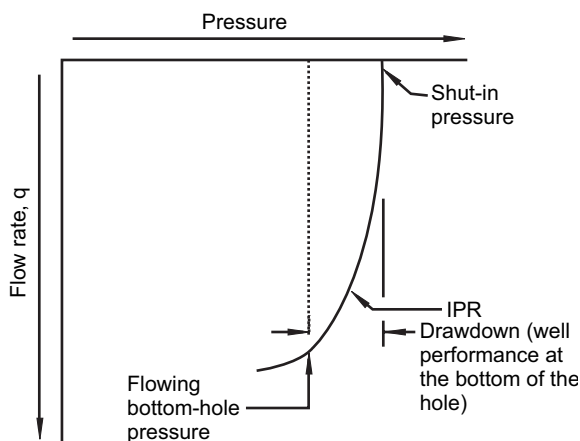


Figure 4.2—Well Performance

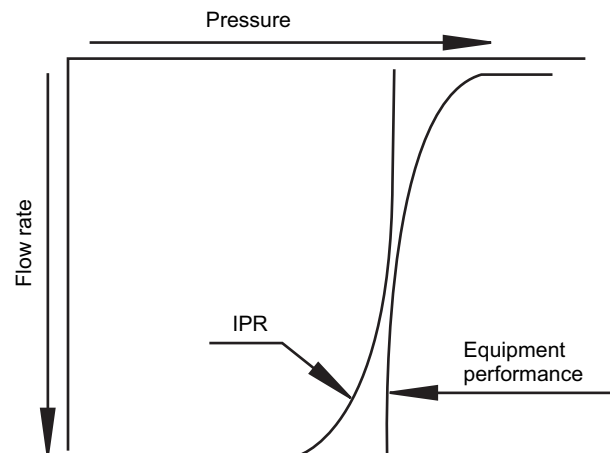


Figure 4.5—Dynamic Kill

1. Pump Rate—Increasing the pump rate results in additional pressure drop, thus more backpressure on the formation.
2. Flow Restriction—When drilling with a BOP, backpressure can be applied by a surface choke.
3. Fluid Density—If drilling without a riser (circulating mud back to the seafloor), backpressure at the formation face is affected by the hydrostatic pressure of the drilling fluid from the bottom of the hole to the sea floor plus the hydrostatic pressure exerted by the sea.

4.4.5 Well Control Design

A well is usually studied at the discharge (surface) or at the formation (bottom), but may be analyzed at any point in the system. The point selected depends on what is being studied. For example, the diverter may be the point of analysis if the effect of vent line size is being evaluated, the riser may be the point of analysis if the effect of riser size is being evaluated, or the choke line if a deepwater subsea stack is being analyzed.

4.5 DRILLING OR WORKOVER FLUID

Drilling fluid properties are of primary significance in well control. The density of the drilling fluid determines the hydrostatic pressure at any point in the static well bore. When a well is circulated, the hydrostatic pressure of the fluid column is combined with the resistance of the fluid to flow, as measured by fluid viscosity, and the pressure drop caused by the friction of the fluids moving through the pipe, equipment, and hole; all must be taken into account to determine pressure at some point in the system. Viscosity is a function of the drilling fluid composition as well as the temperature. Mud system composition varies from the simple to the highly complex. During a kick, the properties of the drilling fluid can be changed due to the influx of formation fluids. For more information on drilling fluids refer to API RP 13D, *Recommended Practice for Rheology and Hydraulics of Oil-Well Drilling Fluids*; API RP 13B-1, *Recommended Practice for Standard Procedure for Field Testing Water-based Drilling Fluids*; and API RP 13B-2, *Recommended Practice for Standard Procedure for Field Testing Oil-based Drilling Fluids*.

4.5.1 Density

Density is the weight of a specific volume of fluid. The density of drilling and workover fluids is commonly referred to “mud weight” and expressed in pounds per gallon (lbs/gal).

4.5.2 Composition

Drilling and workover fluids include air, natural gas, nitrogen, foam, freshwater, saltwater, gelled fresh water, gelled saltwater, seawater, synthetic fluids, and oil-based fluids. The composition of the fluid system design varies with the temperatures, pressures, and composition of the expected forma-

tions and the objectives of the well. Fluid composition may be changed several times during the drilling and completion of a well. Environmental and government regulation can affect selection of drilling fluid composition.

4.5.2.1 Air, Natural Gas, and Foam

These highly compressible drilling and workover fluids require special considerations. They are generally used in areas where low-pressure formations are expected when drilling or conducting remedial cleanout operations. Although these operations are not usually associated with well control problems, well control situations can occur. The hydrostatic pressure exerted by a column of these fluids is small and the fluid density cannot be readily increased. It is important to review field and well history, pressure data, and geology to predict potential problems that might occur and have appropriate contingency plans. In many cases, bullheading (refer to 4.11.1 for bullheading operations) water or other fluid will provide the necessary hydrostatic pressure to regain primary well control.

4.5.2.2 Water-Based Fluids

Included in this category are freshwater, seawater, produced saltwater, and specialized brines such as calcium chloride and zinc bromide. The desired fluid properties are achieved with gels, polymers, inhibitors, and/or weighting material. Water-based fluids are, for all practical purposes, incompressible and relatively (compared to oil based fluids) unaffected by expansion due to temperature; the compressibility and temperature expansion factors that exist tend to cancel each other. However, temperature effects should not be ignored when working with water-based fluids. Natural gas solubility in water-based fluids is negligible. These properties provide a relatively stable and predictable fluid density throughout the circulating system and a relatively predictable choke response. Calculated bottom-hole pressures can be predicted with relative certainty. Hydrate formation in cold temperatures can be a concern and is especially so in deepwater. Hydrate formation can be inhibited with glycols and glycerin additives.

4.5.2.3 Oil and Synthetic Based Fluids

Oil-based fluids can be hydrocarbon and mineral oil based. Synthetic fluids include a number of formulations that simulate the properties of oil-based fluids. Oil and synthetic based fluids can be less dense than water-based fluids; a consideration if less hydrostatic pressure is required to avoid fracturing a formation. However, oil and synthetic based fluids are more sensitive to pressure, temperature, and gas solubility than water-based fluids. For example:

1. Oil and synthetic based fluids are more compressible than water-based fluids and as they compress, they gain

density. This effect becomes more pronounced in deep wells and deepwater.

2. Oil and synthetic based fluids are more temperature sensitive than water-based fluids. High temperatures tend to cause thinning and expansion; low temperatures, the opposite. In onshore and shallow water offshore wells, temperature and compressibility tend to balance each other. The temperature effect is most evident in deepwater where the drilling fluid passes from below the mudline to the large diameter riser where the temperatures are in the range of 35° to 50°F. Choke and kill lines are similarly affected.

3. Natural gas is more soluble in oil and synthetic based fluids than in water-based fluids.

4.6 INFLUX BEHAVIOR

Well influx can consist of gas, water, oil, or any combination of these media. Well influx forms a slug in the well bore. The slug is usually less dense than the drilling fluid and must be removed or pumped back into the formation.

4.6.1 Gas

Gas is a highly compressible fluid; the volume occupied depending on temperature and pressure. Consider a barrel of gas at the bottom of a 10,000-ft well. The bottom-hole temperature is 170°F and the well is full of 9.0 lb/gal drilling fluid, which provides a hydrostatic pressure of 4,680 psi on the gas. This same barrel of gas will expand to occupy a volume of 280 barrels under atmospheric conditions (assuming 0.6 specific gravity gas at 80°F and 14.7 psia). If that barrel of gas is not allowed to expand in a controlled manner as it is circulated up the well bore, it will maintain its initial pressure of 4,680 psi as it moves up the annulus, and may create excessive well bore pressures.

Gas is also highly soluble in oil-base and synthetic- or pseudo-oil-base fluids; therefore, special care is required for detecting kicks and handling them with these fluids. Since dissolved gas kicks become an integral part of the liquid phase, these kicks do not behave the same way as free-gas kicks. Specifically, a gas influx which dissolves is more difficult to detect early, and gas breakout can occur rapidly nearer the surface. Solubility depends on factors such as temperature, pressure and fluid composition. For additional information on solubility effects in deepwater operations, refer to the *IADC Deepwater Well Control Guidelines*.

4.6.2 Water

Water is nearly incompressible; it does not expand to any appreciable extent as pressure is reduced. Due to this property, pumping and returns rates are equal as a water kick is circulated from the well bore, provided no further water influx is permitted or fluid is lost. To maintain constant bot-

tom-hole pressure, the casing pressure must be allowed to decline as the lighter water is displaced and heavier drilling fluid replaces it in the annulus. An increase in drilling fluid density during a well kill operation also changes the casing pressure. Nearly all water influxes contain some solution gas, which requires that surface pressures follow a pattern similar to that seen during a gas kick.

4.6.3 Oil

Like gas-charged saltwater, oil behaves essentially like a smaller gas influx.

4.7 FORMATION INTEGRITY TESTS

The pressure at which a formation fractures determines whether the open-hole section can withstand the pressures found in deeper formations. Two tests are designed to yield this information: the leak-off test and the formation competency test. It is important to have accurate drilling fluid density and pressure data for these tests to yield meaningful results. Use representative samples for measuring the fluid density and use a pressure gauge with the appropriate scale and that has been calibrated.

4.7.1 Leak-off Test

A leak-off test is made to determine the pressure at which a formation will fracture. It is usually run after drilling a short distance below the surface casing shoe and may be run as other casing strings are run as well. The test is performed by pumping drilling fluid into the well bore at a slow rate (typically one-half barrel per minute) with the BOP closed and plotting the resulting pressure versus the total volume pumped. The pressure at which the plotted curve begins to flatten, i.e., when the pressure increases a smaller amount for a volume pumped, is the surface leak-off pressure. At that point, the pump should be stopped immediately. This pressure plus the hydrostatic pressure of the drilling fluid is the formation fracture pressure.

$$\begin{aligned} \text{Formation fracture pressure (psi)} = & \\ & \text{Leak-off pressure (psi)} + \\ & [0.052 \times \text{Drilling fluid density (lb/gal)} \times \text{Casing TVD (ft)}]. \end{aligned}$$

4.7.1.1 It is useful to calculate the formation fracture gradient as equivalent or fracture drilling fluid density.

$$\begin{aligned} \text{Fracture drilling fluid density (lb/gal)} = & \\ & \frac{\text{Leak-off pressure}}{0.52 \times \text{Casing TVD (ft)}} + \\ & \text{Drilling fluid density in use during test (lb/gal)} \end{aligned}$$

4.7.1.2 Fracture pressure is the maximum surface pressure that can be applied to a casing that is full of drilling fluid.

without fracturing the formation. Fracture pressure is calculated as follows:

$$\begin{aligned} \text{Fracture pressure (psi)} = & \\ & 0.052 \times \text{Casing TVD (ft)} \times \\ & [\text{Fracture drilling fluid density (lb/gal)} - \\ & \text{Present drilling fluid density (lb/gal)}]. \end{aligned}$$

4.7.2 Formation Competency Test

A formation competency test is made to determine if a well bore will support drilling fluid of a higher density at some future time during the well drilling operations. Perform the test by pumping drilling fluid into the well bore at a slow rate, typically one-half barrel per minute, with the BOPs closed. Pump into the well bore until reaching the predetermined test pressure as calculated below:

$$\begin{aligned} \text{Test pressure (psi)} = & \\ & 0.052 \times \text{Casing TVD (ft)} \times \\ & [\text{Required test drilling fluid density (lb/gal)} - \\ & \text{drilling fluid density currently in use (lb/gal)}]. \end{aligned}$$

During the test, plot surface pressure against volume pumped. If the plotted curve begins to flatten or the pressure decreases, pumping should be stopped immediately (refer to 4.7.1).

4.8 WELL CONTROL PRESSURES

Well control design and procedures require measurement and calculation of pressure at several points in a well and well control system. A circulating well is more complicated than the static well illustrated in Figure 4.1. This is due to the friction generated by the flow of fluid in the well piping, the open hole, and the inherent resistance of liquids to flow. Pressure must be applied to overcome these forces to circulate a well. Pressure applied at the top of a drilling string alters pressures throughout the pipe and hole. In fact, fluid circulation creates additional overbalance that can help control the well but may also cause excessive pressure that can lead to formation fracture. Several pressure measurements, calculations, and concepts are discussed below with examples to illustrate their significance.

4.8.1 Pressure Measurement

Pressure measurement is a key component of well control. Pressure gauges should be in good working order and calibrated per the recommendations in Section 17 (Surface BOP) and Section 18 (Subsea BOP) of API RP 53, *Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells*. Select a gauge with a display range appropriate to the pressure information required.

4.8.2 Static Well Pressures

To understand how the various pressures interact, it is necessary to isolate and identify each one. Figure 4.6 illustrates various pressures in a static well bore. The drill pipe gauge pressure plus the hydrostatic pressure of the drilling fluid equals the bottomhole pressure. The same pressure balance can be made for the annulus, i.e., casing gauge pressure plus the hydrostatic pressure of the annulus drilling fluid plus the hydrostatic pressure of the influx equals the bottomhole pressure.

4.8.3 Circulating Pressures

The main pressure losses that occur in a circulation system are:

1. Friction losses inside the drill pipe, casing, or work-over string;
2. Pressure drop across the nozzles or water courses in the bit or shoe;
3. Friction loss in the annular space between the well bore and pipe; and,
4. Friction loss in the surface piping and connections.

The total pressure at the bottom of the hole while circulating is the sum of the combined annular fluid column pressure (hydrostatic head) plus the annular friction pressure plus imposed surface backpressure. The drill pipe circulating pressure is the sum of all friction losses plus corrections due to density imbalances between the drill pipe and the annulus plus any imposed surface backpressure.

4.8.4 Equivalent Circulating Density

The density equivalent of friction pressure in the annulus plus the drilling fluid density in the hole is often expressed as equivalent circulating density (ECD). Figure 4.7 illustrates an example. In this case, the circulating pressure applied to the drill pipe is 2,800 psi. It is largely used to overcome friction of flow through the drill string and bit so that only 200 psi remain to increase pressure in the well bore at bottom. The additional pressure at bottom is due to the friction loss in the annulus. The annular friction circulating pressure is equivalent to increasing the drilling fluid density by 0.4 lb/gal. No increase in pressure occurs at the top of the annulus when circulating.

ECDs greater than formation fracture pressure cause loss of mud and well control problems. ECD is relatively high in some operations due to a combination of hole size, drill string OD, measured depth, and mud properties. Some examples are slimhole drilling and some high-angle or horizontal wells. When circulation stops in these operations, there may be a significant bottomhole pressure reduction. Therefore, it is important to flow check the well when circulation stops to ensure the well is stable without the ECD effects. Pressure measurement while drilling can be very useful in monitoring

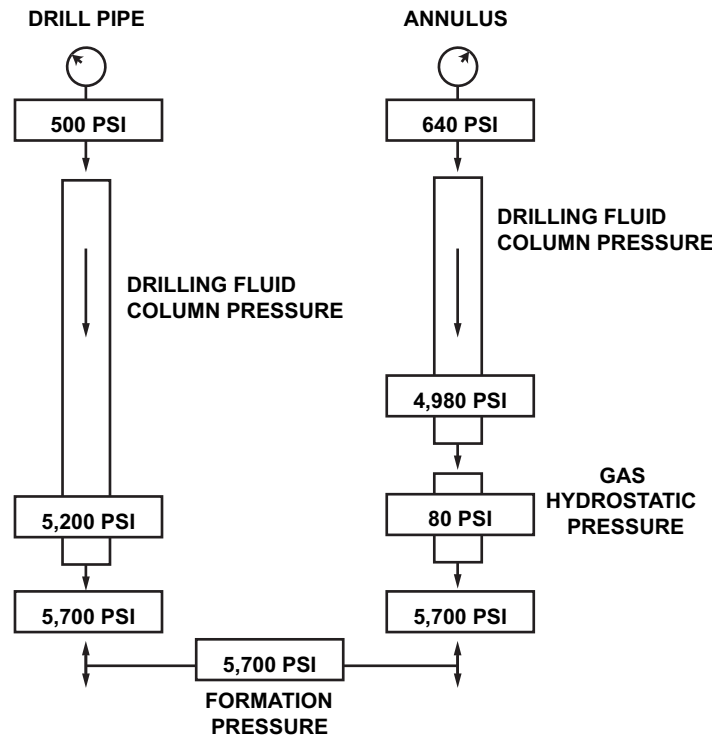


Figure 4.6—Static Well Kick Pressures

ECD. It allows further modeling and calibration of the circulation system.

4.8.5 Reduced Circulating Pressure or Kill-Rate

For use in well kill operations, a circulating pressure is generally measured at a convenient reduced circulating (kill) rate. Kill rates are selected based on the ability of the pumps to pump slow, the ability of the mud mixing equipment to weight up mud, maximum circulation pressures, mud gas separator capacity, and choke reaction time, and choke line pressure drop (in the case of subsea wells). The stroke rate and pressure are recorded on the tour sheet for each pump and redone whenever the circulating system pressure is significantly changed, i.e., drilling fluid density, bit nozzles, or over 500 ft of hole is drilled, etc. Reduced circulating pressures are usually required when circulating kicks so that the additional pressure required to prevent formation flow can be added without exceeding the pump discharge pressure rating. The slower circulating rate also simplifies drilling fluid material mixing procedures and handling returns through the choke. In offshore situations, however, it may be desirable to circulate out a kick as rapidly as possible to minimize exposure to

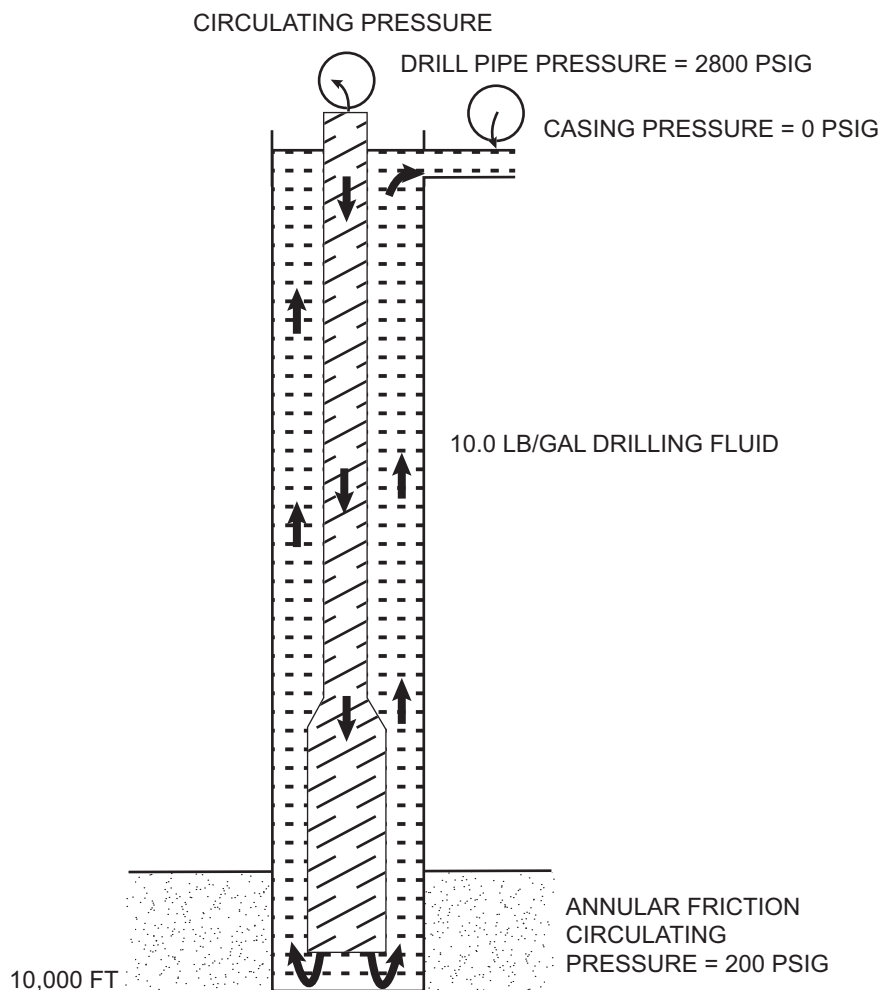
adverse weather. The solution to these conflicting objectives is to initiate the well kill at the highest circulating rate that will not cause loss of circulation and reduce the circulation rate preferably before gas reaches the choke line. The example well control worksheet for deepwater operations illustrates a procedure for accomplishing this (refer to Appendix B). Guidance for pre-selecting kill-rates in deepwater is contained in 4.13.4.

4.8.6 Initial and Final Circulating Pressures

An initial and final circulating pressure are used when circulating out kicks. These pressures are a necessity when using the Wait and Weight or Concurrent Weight-up Methods described in 4.10.

4.8.6.1 Initial Circulating Pressure

The initial circulating pressure is the drill pipe pressure after bringing the pump up to the kill-rate while holding casing pressure constant at the closed-in value. It is also equal to the closed-in drill pipe pressure plus the measured circulating pressure at the selected kill-rate (refer to Figure 4.11).



EQUIVALENT

$$\text{CIRCULATING DENSITY} = 10 \text{ LB/GAL} + \frac{\text{ANNULAR FRICTION CIRCULATING PRESSURE}}{.052 \times \text{TVD}} = 10.4 \text{ LB/GAL}$$

Figure 4.7—Equivalent Circulating Density

4.8.6.2 Final Circulating Pressure

The final circulating pressure is the measured circulating pressure at the selected kill-rate corrected for drilling fluid density increase.

$$\begin{aligned} \text{Final Circulating Pressure (psi)} = & \\ & \text{Kill-rate Pressure (psi)} \times \\ & \frac{\text{New Drilling Fluid Density (lb/gal)}}{\text{Old Drilling Fluid Density (lb/gal)}} \end{aligned}$$

4.8.6.3 Example: Figure 4.11 shows that, before the kick, the driller measured 750 psi at a kill-rate of 30 strokes per minute, or 4.5 barrels per minute, using a 10.0 lb/gal drilling

fluid. The shut-in drill pipe pressure of 520 psi indicates a required drilling fluid density of 11.0 lb/gal at 10,000 feet.

Final Circulating Pressure (psi) =

$$750 \text{ psi} \times \frac{11.0 \text{ lb/gal}}{10.0 \text{ lb/gal}} = 825 \text{ psi}$$

4.8.7 Closed-in Drill Pipe and Annulus Pressure

Formation pressure near the well bore is reduced during flow. When a well is closed-in, the borehole pressure rises until equal to formation pressure. As the drill pipe and annulus are in communication with the borehole, the drill pipe pressure will also rise and stabilize. The stabilized drill pipe

pressure indicates the amount to increase the drilling fluid density to balance the formation pressure. If the well is not circulated, the gas influx will slowly migrate up the hole and increase the well bore and drill pipe pressures. Therefore, drill pipe pressures after the initial stabilized reading indicate excessive drilling fluid density increase. The initial stabilized pressures are very important; they are the basis for determining the fluid density required to regain primary well control. To avoid excess well bore pressure due to the gas influx migrating up the hole, use a choke to bleed drilling fluid from the casing and maintain the initial shut-in drill pipe pressure. These conditions are illustrated in Figure 4.9.

4.8.7.1 Example: Stabilized Pressures of a Well Closed-In on a Kick—Figure 4.8, is a schematic diagram of a well shut-in on a kick. A 20-barrel gas influx occurs while drilling at 10,000 ft with a 10.0 lb/gal drilling fluid. The stabilized closed-in pressures are 500 psi on the drill pipe and 640 psi on the casing or annulus gauge.

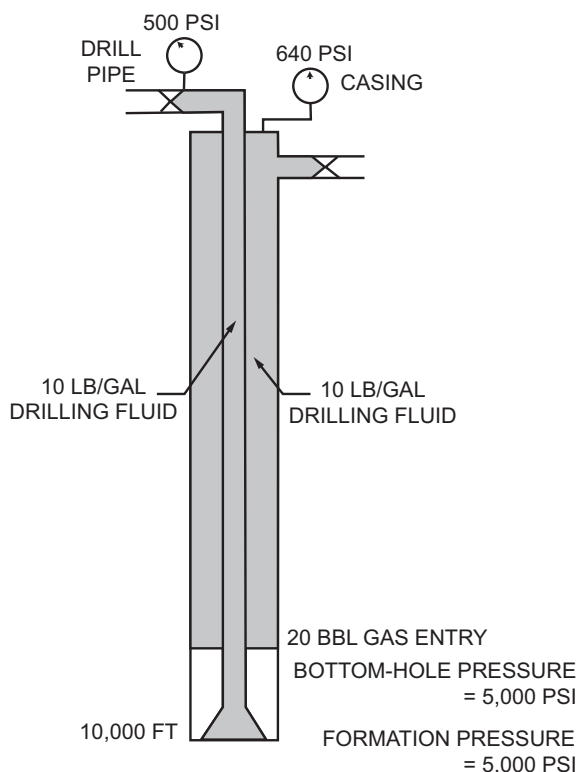


Figure 4.8—Well Closed-In on a Kick

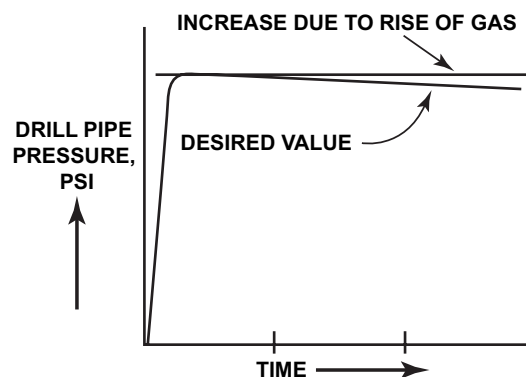


Figure 4.9—Closed-In Drill Pipe Pressure

4.8.7.2 Example: Closed-In Drill Pipe Pressure with a Backpressure Valve, Figure 4.9, to determine the closed-in drill pipe pressure when a backpressure valve is in the drill string, pressure should be increased slowly using the smallest pump available to open the backpressure valve. That pressure is the closed-in drill pipe pressure. If casing pressure rises while pumping on the drill pipe, pumping should be stopped and the increase in casing pressure subtracted from drill pipe pressure.

4.8.7.3 Example: Gas Influx Migrating Up The Hole—Figure 4.10, illustrates an example of a 10,000 ft closed-in well with 10.0 lb/gal drilling fluid and a small volume of gas at bottom. When the gas rises to 5,000 ft without expansion or temperature change, the bottom-hole pressure rises to 7,800 psi, which is equivalent to a 15.0 lb/gal drilling fluid column. When the gas reaches the surface, bottom-hole pressure is 10,400 psi, which is equivalent to a 20.0 lb/gal drilling fluid column. At 5,000 ft the borehole pressure is equivalent to a 30.0 lb/gal drilling fluid column to that depth. Such excessive pressure should be avoided whether gas rises through a static drilling fluid column or circulated out by allowing the gas to expand as it rises. This situation requires that the pits be allowed to gain volume. If a gas bubble is permitted to rise in a well bore without expanding, the gas pressure will remain constant. The reduced hydrostatic head above the gas column must be overcome by increased surface pressure on the casing; in turn, this increased pressure results in a higher bottom-hole pressure.

4.9 WELL CLOSE-IN PROCEDURES

When a kick is detected, the well should be closed-in as quickly as possible to minimize influx volume. There are two close-in procedure options, the soft close-in and the hard close-in. The hard close-in minimizes kick influx volume is less complicated, can be performed by one person working on the rig floor, and is usually performed faster than the soft close-in procedure.

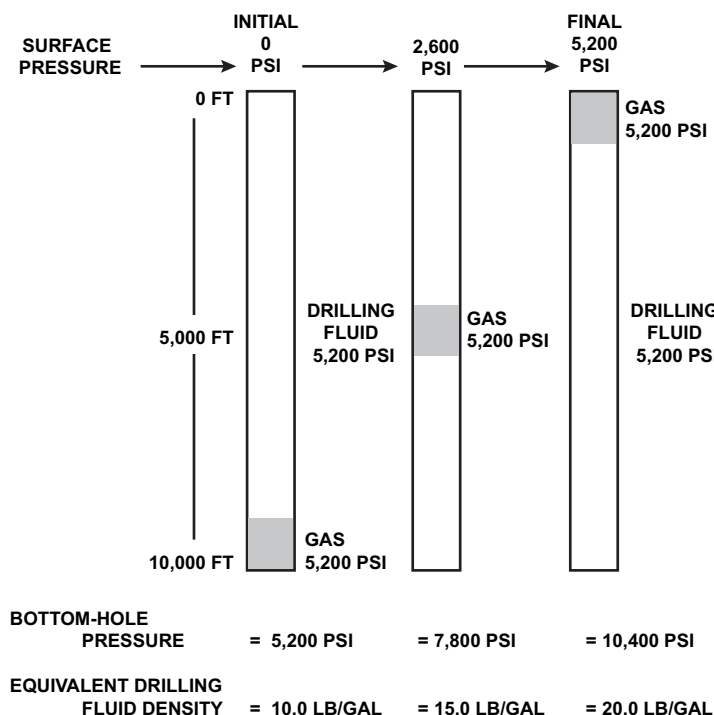


Figure 4.10—Gas Influx Migrating Up The Hole

4.9.1 Soft Close-in Procedure

A choke is left open at all times other than during a well control operation. This permits control and monitoring of casing pressure buildup during closure, an important feature if formation fracturing and broaching to the surface is likely or if the initial closed-in casing pressure is likely to exceed the maximum allowable casing pressure. The soft close-in procedure permits initiation of pre-identified alternate procedures, such as the low choke procedure (see 12.3.5) before maximum allowable casing pressure is reached. The major disadvantage of the soft close-in procedure is that the additional time involved in opening the choke line valve and closing the choke allows additional influx into the well bore. This results in a larger kick volume and potentially higher casing pressure while circulating out the kick thus complicating well control. If the soft close-in procedure is contemplated, it should be given consideration in the well pre-planning phase where other steps may be identified to alleviate its need (higher strength casing, additional casing strings, etc), it can be well planned, and training and drills can be considered.

With the exception of one choke line valve located near the BOP, the choke line valves are aligned such that a flow path is open through the choke system. The soft close-in procedure is:

1. Open the choke line valve.
2. Close the BOP.
3. Close the choke.

4.9.2 Hard Close-in Procedure

The BOP is closed and the chokes remain closed at all times other than during a well control operation. The procedure is simple, allows well closure in the shortest possible time, and minimizes additional influx into the well bore. It is limited to well conditions where the maximum allowable casing pressure is greater than the anticipated initial close-in pressure and a well fracture would not be expected to broach to the surface on initial closure. With the exception of the choke(s) itself and one choke line valve located near the BOP stack, the choke line valves are aligned such that a flow path is open through the choke system. If the casing pressure cannot be measured at the wellhead, the choke line valve is opened with the choke, or adjacent high-pressure valve, remaining closed so that pressure can be measured at the choke manifold.

4.10 METHODS FOR CIRCULATING KICKS AT CONSTANT BOTTOM-HOLE PRESSURE

After a kick is stopped by well closure, circulation should be established, the kick circulated to the surface at constant bottom-hole pressure to avoid further influx, and drilling fluid density increased to establish primary well control (refer to Section A-1 in Appendix A). When circulation can be established, there are three methods of circulating out kicks:

1. Driller's Method—The well is closed-in; then the kick is circulated out without increasing the drilling fluid den-

sity; after the kick is circulated out, drilling fluid of required density circulated.

2. **Wait and Weight Method**—The well is closed-in; the drilling fluid density is increased in the pits as required; then the kick is circulated out with the required density fluid.

3. **Concurrent or “Circulate and Weight” Method**—The well is closed-in; then circulation is resumed as soon as pressures stabilize; addition of weight material to the drilling fluid is begun as soon as circulation is started.

4.10.1 Establishing Circulation

The recommended procedure to establish a steady circulating rate while keeping a constant bottom-hole pressure is as follows:

1. Concurrently open the annulus choke and slowly bring the pump up to the selected kill-rate speed.
2. While bringing the pump up to speed, adjust the choke to hold the casing pressure constant at the closed-in value. Holding the casing pressure constant at the closed-in value for the short time required to bring the pump up to speed holds the bottom-hole pressure essentially constant.
3. With the pump running at the desired speed and the casing pressure stabilized at the desired value, read the drill pipe pressure. The drill pipe pressure read at this point is that pressure necessary to maintain a constant bottom-hole pressure as long as the mud weight and pump rate are held constant. The difference between the closed-in and pumping drill pipe pressure is the pressure required to cause the drilling fluid to circulate at the desired rate.
4. Determine the sum of the closed-in drill pipe pressure and the pre-recorded kill-rate circulating pressure. If the drill pipe pressure is appreciably different, investigate the cause.

Note: Changes in pressure due to choke manipulation require approximately two seconds per 1,000 feet of drill string to register on the standpipe gauge; however, this lag in response time can be longer if a large gas kick is present.

5. Keep the drill pipe pumping pressure constant by manipulating the annulus choke, while holding a constant pump rate. If the drilling fluid density in the drill string is increased, reduce the drill pipe pressure to maintain a constant bottom-hole pressure.

4.10.1.1 Annular friction pressure can be viewed as a safety factor to prevent formation fluid flow. This is because, in a circulating well, bottom-hole pressure exceeds formation pressure by the amount of the annular circulating pressure. Annular friction pressure is usually in the range of 50 – 200 psi at 10,000 ft, which is the equivalent of a 0.1 – 0.4 lb/gal increase in the density of a static drilling fluid column.

Note: Additional casing pressure may be applied to provide more safety factor. This additional safety factor should be chosen carefully

based on ability to manipulate choke pressure to desired values and fracture pressure of the last casing seat. Extra care should be taken with only surface pipe set because shallow formations may break-down easily. In general, it is recommended the well be killed first then raise the drilling fluid weight to provide the desired overbalance.

4.10.1.2 Establishing circulation is not always possible, practical or desirable. In those cases, refer to 4.11 for bull-heading and top-kill kill methods and to Section 13 for addressing lost circulation and underground blowouts.

4.10.1.3 Example: Stabilized Pumping of a Kick—Figure 4.11 illustrates a well just after circulation is initiated. The well was initially closed-in with 520 psi on the drill pipe and 875 psi on the annulus. Circulation was initiated and the choke adjusted to keep 875 psi on the casing while the pump is brought up to the kill-rate of 4.5 barrels per minute (30 strokes per minute). When the kill-rate is reached, a pumping pressure of 1,270 psi on the drill pipe is indicated. The pumping pressure is composed of the kick pressure of 520 psi plus the pressure necessary to overcome the friction losses in the various parts of the circulating system as shown. The friction loss (750 psi) at 30 strokes per minute should have been measured and recorded previously. Since the drill pipe pressure is the same as the sum of the closed-in drill pipe pressure and the kill-rate pressure (520 psi + 750 psi), no adjustment in drill pipe pressure is necessary (refer to 9.6.4). The annular circulating pressure is assumed to be about 50 psi. The bottom-hole pressure is equal to the sum of the casing pressure plus the hydrostatic pressure of the annular fluids plus the annular circulating friction pressure. The bottom-hole pressure is also equal to the drill pipe pressure plus the hydrostatic pressure of the fluid in the drill string less the friction pressure loss in the drill string and bit. The bottom-hole pressure is also equal to the closed-in drill pipe pressure plus the hydrostatic pressure of the fluid in the drill string plus the annular circulating friction pressure loss.

4.10.2 Driller's Method

The casing pressure required to maintain a constant bottom-hole pressure is dependent on the type of formation fluid and a changing vertical length of formation fluid in the annulus. Under actual conditions, neither the type nor height of formation fluid is known. Therefore, drill pipe pressure control should always be used to keep constant bottom-hole pressure when circulating kicks out of the annulus. In the drill pipe, drilling fluid density is known and the drill pipe pressure can be read on the gauge. These factors, properly used, determine bottom-hole pressure with relative certainty.

4.10.2.1 The procedure described for establishing circulation (refer to 4.10.1) results in a desired drill pipe pressure at a constant kill-rate. To circulate a kick at constant bottom-hole pressure without increasing drilling fluid density, circulating rate and drill pipe pressure should be constant. Drill

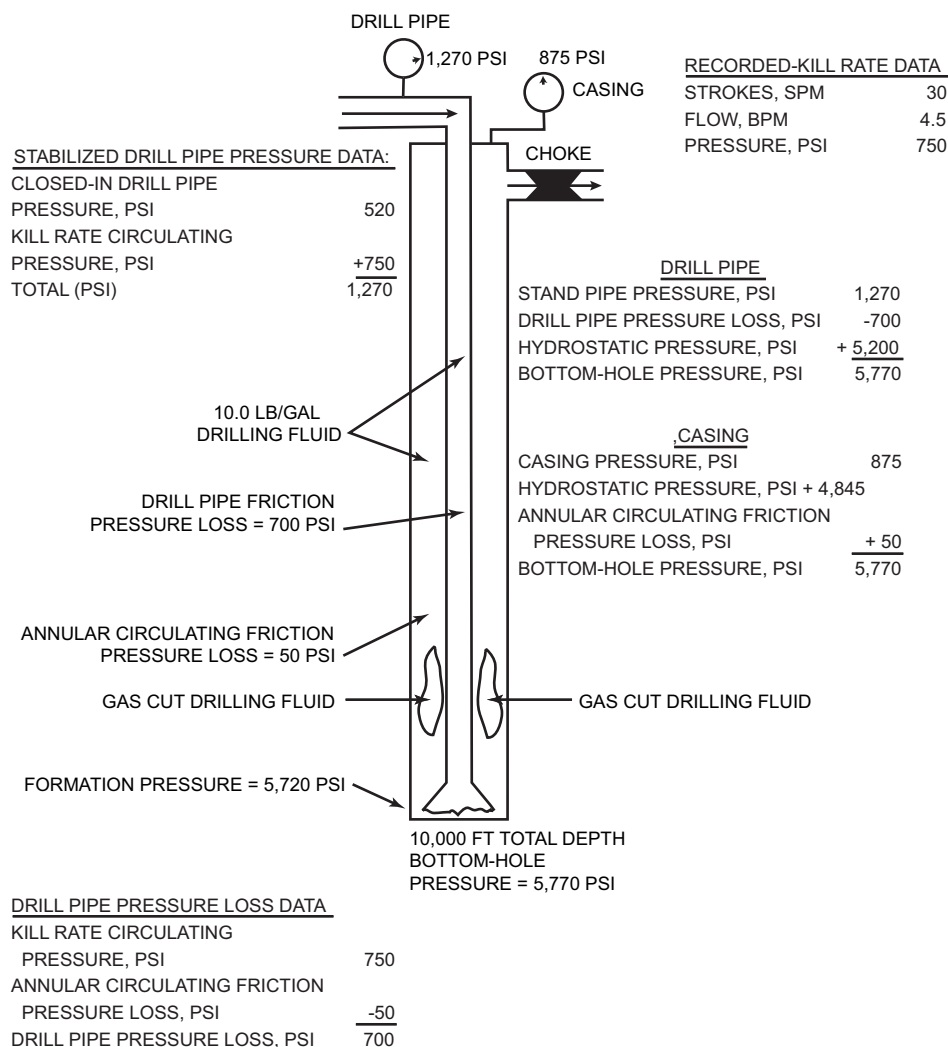


Figure 4.11—Stabilized Pumping Of A Kick

pipe pressure should be held constant by choke manipulation. Circulation can be stopped at any time and the choke closed by keeping casing pressure constant while stopping the pump. Closed-in drill pipe pressure should be the same as when the well was originally closed.

4.10.2.2 During circulation of the kick, gas expansion and pit volume gain should be allowed. As drilling fluid volume in the annulus decreases due to gas expansion, higher casing pressures will result to maintain constant bottom-hole pressure; but the correct bottom-hole pressure will result at all times from proper control of drill pipe pressure.

4.10.2.3 After the kick is circulated out without increasing drilling fluid density, the annulus should be full of drilling fluid. When the well is closed-in, the pressure on the drill pipe and casing should be the same as the original closed-in

drill pipe pressure. However, the well is not dead at this point. The well should be closed-in and the drilling fluid density increased in the pits to the required value.

4.10.2.4 Circulation of heavier fluid down the drill pipe at a constant rate will change the circulating drill pipe pressure and eliminate the closed-in drill pipe pressure. The drilling fluid density in the annulus will not change while the heavier fluid is pumped to the bit, therefore a simple way to control bottom-hole pressure is to use constant casing pressure. After the heavier drilling fluid passes the bit, the casing pressure will change; but drill pipe pressure need not change and can be used for control. The steps are as follows:

1. Establish circulation at the selected kill-rate as described in 4.10.1. Hold casing pressure constant at the closed-in value by choke manipulation while bringing the

pump to speed and thereafter until heavy drilling fluid reaches the bit.

2. When the heavy drilling fluid reaches the bit, read the drill pipe pressure gauge and hold the drill pipe pressure constant at the kill-rate by manipulating the choke until the heavy drilling fluid reaches the surface.

3. Shutdown the pump and check for flow.

4.10.2.5 Example: Driller's Method of Circulating Out a Kick—Figure 4.12 illustrates an example of casing pressure and pit volume increase based on the well conditions shown in Figure 4.11. Initial closed-in drill pipe and casing pressures are 520 psi and 875 psi respectively. When circulation is started, a 50-barrel gas influx is alongside the drill collars and the lower part of the drill pipe. The initial closed-in casing pressure is 875 psi and kick volume is 50 barrels as shown at point A. When 25 barrels of drilling fluid is pumped, the gas bubble is alongside the drill pipe and its total length is shortened in the larger annulus. This produces a longer column of drilling fluid and less casing pressure is required at point B to balance bottom-hole pressure. Gas expansion is slow at first, increasing as it rises in the hole. Maximum casing pressure, gas volume in the hole, and pit gain occur when the gas reaches the surface at point C. Between points C and D, the casing pressure decreases rapidly as gas is being replaced in the well by drilling fluid. Pit volume decreases accordingly. At point D all gas is removed and casing pressure is the same as the original closed-in drill pipe pressure. Casing pressure and drill pipe pressure are the same because 10.0 lb/gal drilling fluid fills both the drill pipe and annulus. During a kick while drilling, gas flows into the circulating drilling fluid and a mixture occurs. When the well is shut-in, gas migrates up the hole. While circulating the kick, the gas generally rises faster than the drilling fluid. Because the drilling fluid flow rate outside the drill string is not the same at all points across the hole, some gas will be pushed ahead during the circulation and some will lag. As a result, casing pressures are not exactly as discussed for a single bubble nor are they precisely calculable. Fortunately, the peak casing pressure can be expected to be somewhat less and will occur sooner than displacement volume would indicate as shown at point C in Figure 4.13. Due to lag of gas, some additional volume of drilling fluid will be pumped before the well is free of gas as shown in Figure 4.13.

4.10.3 Wait and Weight Method

When the Wait and Weight Method is used, the well is closed-in on the kick, drilling fluid density is increased as required, and the kick is circulated out using the weighted fluid. Circulation is established at the kill-rate as described in 4.10.1. Drill pipe pressure is used to control bottom-hole pressure because of gas expansion in the annulus, but the required drill pipe pressure changes as the pipe fills with the

heavy drilling fluid. Drill pipe pressure is maintained by manipulation of the choke.

4.10.3.1 A schedule of drill pipe pressure change should be prepared and followed. Figure 4.14 shows such a schedule based on the conditions of the 50-barrel kick illustrated in Figures 4.11 and 4.12. Initial circulating pressure is plotted above zero pumpstrokes, and final circulating pressure is plotted above pumpstrokes to the bit. A line is drawn between the two points. If a pumpstroke counter is not available, the drill pipe pressure reduction schedule can be constructed using either minutes or barrels instead of pumpstrokes in Figure 4.14. These values are the drill pipe pressures to hold at the strokes, minutes or barrels shown.

4.10.3.2 The final circulating pressure is held until the heavy drilling fluid circulates around, reaches the surface and the well is dead. Casing pressures and pit volume increases shown in Figure 4.15 are entirely the result of controlling drill pipe pressure. The original closed-in casing pressure is at point A. At point B the gas bubble has been displaced to alongside the drill pipe and has shortened in the larger annulus, thus requiring less casing pressure. At point C, the balancing density drilling fluid enters the annulus and begins to reduce the casing pressure.

At point D, the gas begins to expand rapidly, forcing drilling fluid from the hole and increasing casing pressure. At point E, gas reaches the surface. From points E to F, gas escapes and is replaced by drilling fluid, reducing casing pressure. At point F, light drilling fluid in the drill pipe at the time of well closure reaches the surface and the casing pressure continues to drop until the balancing drilling fluid density reaches the surface and casing pressure is zero. Not shown is pit volume increase due to addition of barite. Note: Due to resistance to flow in the choke line and open choke, a small casing pressure may remain when balancing drilling fluid density reaches the surface. The pressure should be less than 100 psi and will bleed off when the pump is stopped.

4.10.4 Concurrent Method

When the Concurrent Method (also called "Circulate and Weight Method" and "Slow Weight-up Method") is used, the well is closed-in on the kick and circulation resumed as soon as pressures stabilize. Addition of weight material begins as soon as circulation is started.

4.10.4.1 Circulation should be established as described in 4.10.1. Due to gas expansion in the annulus, drill pipe pressure must be controlled to maintain balanced bottom-hole pressure. Changing drilling fluid density alters the circulating pressure required to maintain the balanced bottom-hole pressures so a schedule of drill pipe pressure should be prepared and followed by manipulating the choke. As the drilling fluid density increases continuously until the suction pit reaches

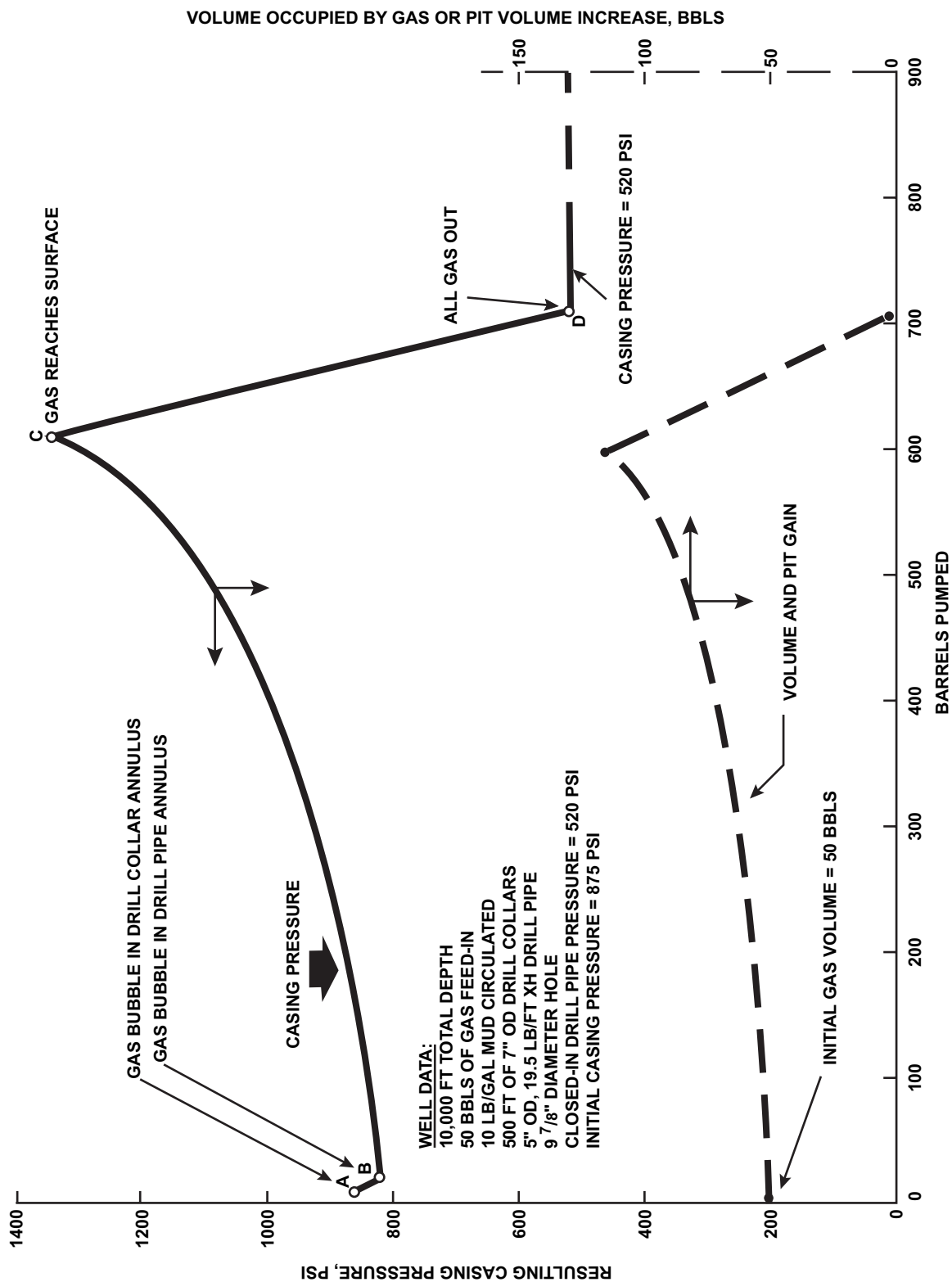


Figure 4.12—Casing Pressure And Gas Volume Resulting From Using The Driller's Method

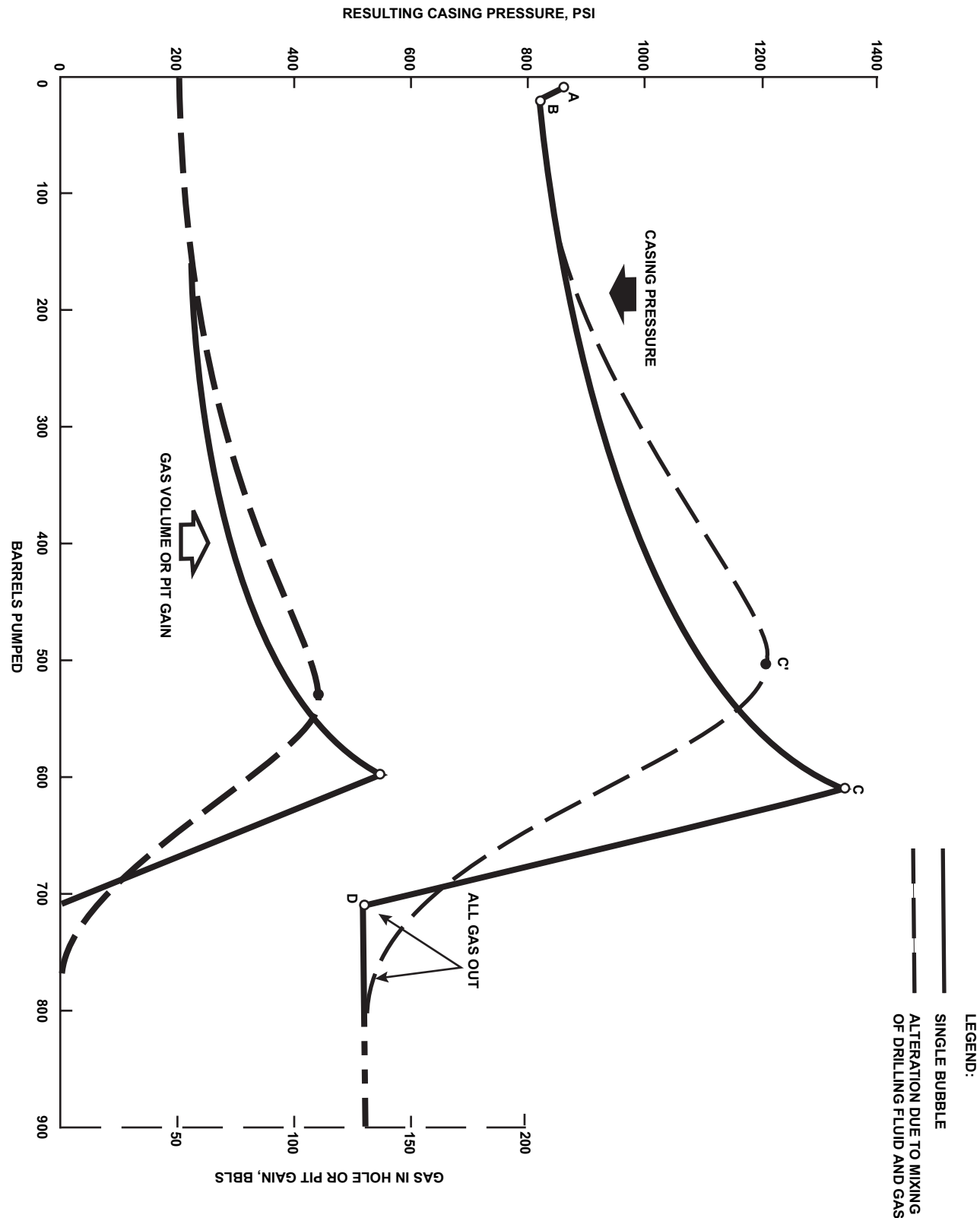


Figure 4.13—Casing Pressure and Gas Volume Using the Driller's Method

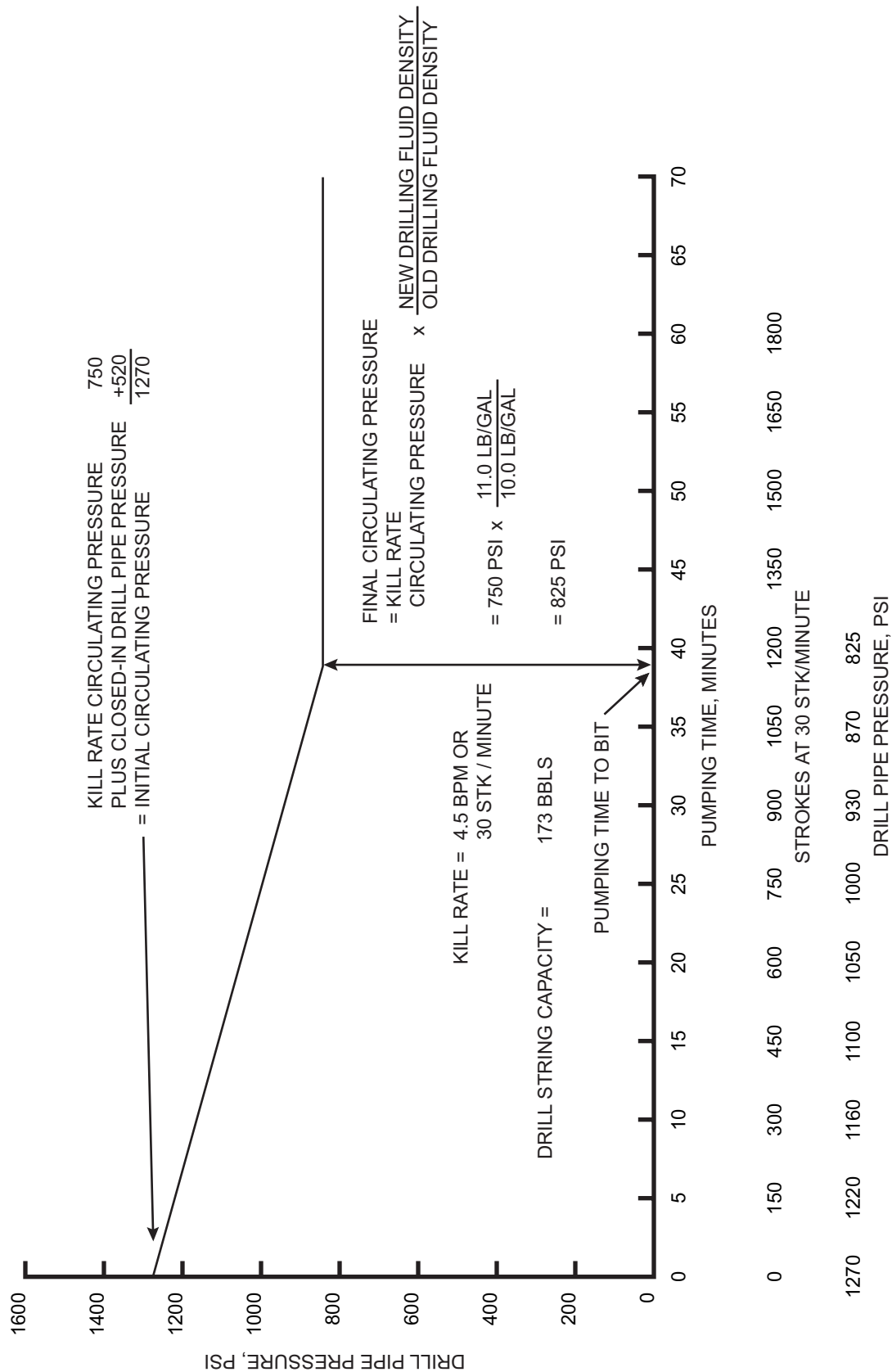


Figure 4.14—Drill Pipe Pressure Schedule for the Wait and Weight Method



Documents

Document Sharing Hub

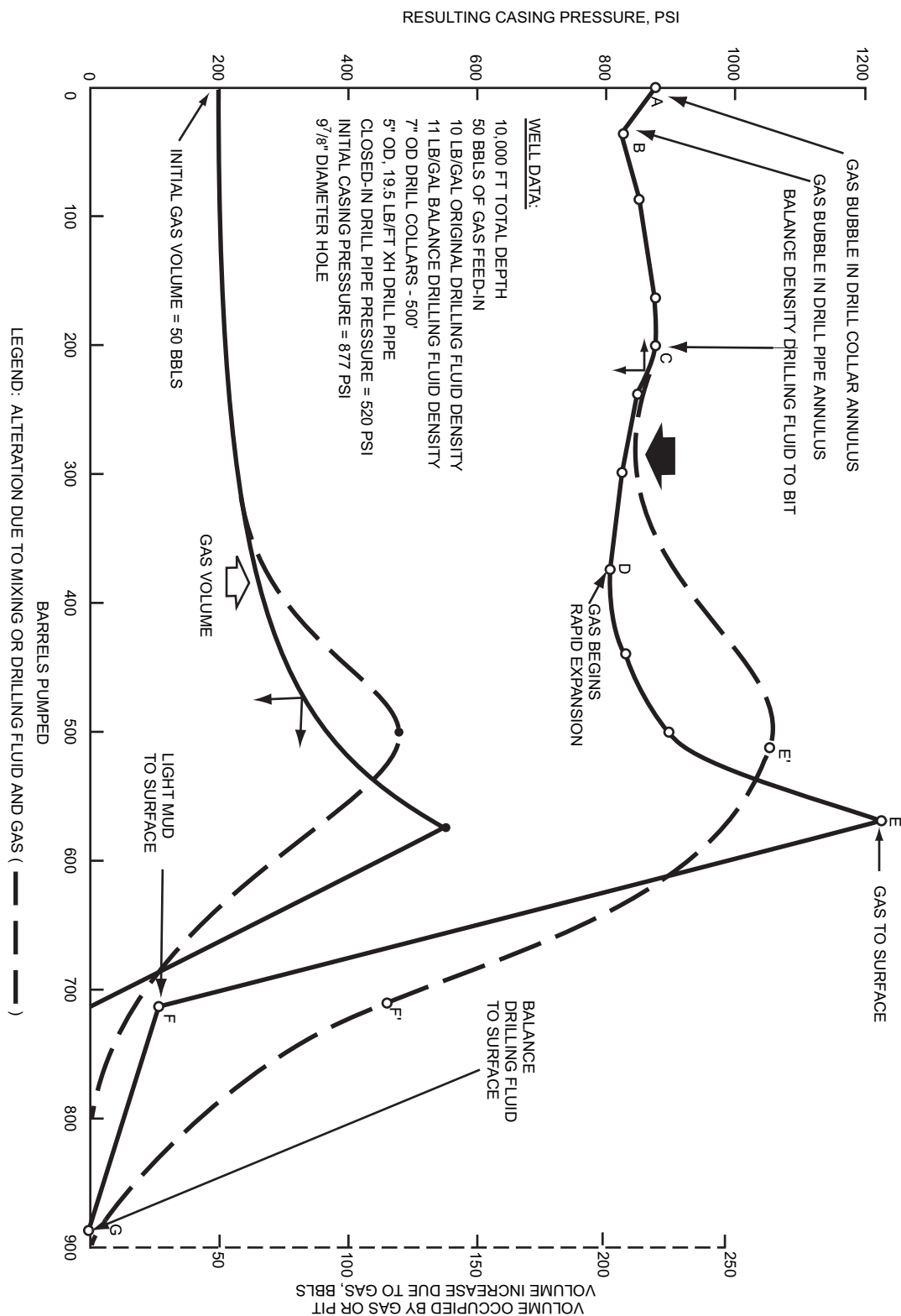


Figure 4.15—Typical Casing Pressure Resulting from Using Wait and Weight Method